Formal Information & Comment Forums
Loveland Area Projects &
WACM Balancing Authority

Proposed
Transmission & Ancillary Services
Formula Rates

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Introduction

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Loveland, CO

9:00 –11:00	Formal Information Forum
11:00 – 1:00	Break
1:00 – NLT 2:30	Comment Forum

Agenda

– Rate Process Schedule

– Why We’re Here

– Informal Meeting Summary

– Rate Proposals

– Summary

– Next Steps

– Contact Information

Rate Process Schedule

Date	Action
September 29, 2010	Held Informal Meeting with Customers in Loveland
January 10, 2011	Published Rate Extension for Current Rates
January 28, 2011	Published Federal Register Notice (FRN) for Rate Proposals—Began 90-day Comment Period
March 9, 2011	Public Information Forum and Public Comment Forum
April 28, 2011	End of 90-day Comment Period
August 2011	Publish FRN for Final Formula Rates
October 1, 2011	Proposed Implementation of New Rate Formulas and Rates

Why We're Here

- Western's OATT (Open Access Transmission Tariff)
  - Originally filed 1/6/98, Revised 1/25/05
  - To comply with FERC 888
- Revised OATT filed 9/30/09 (effective 12/1/09)
  - To comply with FERC 890 and Western's statutory & regulatory requirements
- Move toward common interpretation and implementation of Tariff provisions

- Formula rates have been extended and are set to expire February 28, 2013 (Rate Order WAPA-154)
  - LAP Transmission Rates
    - Network
    - Point-to-Point (Firm and Non-Firm)
    - Transmission Losses
  - WACM Ancillary Service Rates
    - Scheduling, System Control and Dispatch
    - Reactive Supply and Voltage Control from Generation or Other Sources
    - Regulation and Frequency Response
    - Energy Imbalance
    - Operating Reserves – Spinning Reserves
    - Operating Reserves – Supplemental Reserves

Why We're Here

- New Rates:
  - Generator Imbalance
  - Penalty Rate for Unreserved Use of Transmission

Informal Meeting Summary

- Discussed:
  - Proposed changes to each rate
  - Introduced new rates for Generator Imbalance and Unreserved Use of Transmission
  - Written responses to questions were posted to Western's web site on Nov 1, 2010
  - Brochure posted to web site on Feb 7, 2011
  - Brochure Addendum posted to web site on Feb 25, 2011

The rates we're presenting today are the best estimates that we have at this time. They will be revisited before the final FRN is published.

Rate Proposals

Transmission

LAP Transmission Rate Formulas
Attachment H, Schedules 7 & 8

Formula for Network Transmission:

Monthly Charge = Load Ratio Share x Annual Transmission Revenue Requirement (ATRR) x 1/12

Formula for Point-to-Point:

$$\text{Rate} = \frac{\text{(ATRR)}}{\text{LAP Transmission System Load}}$$

No Change to Existing Formulas

Estimated FY 12 Rates

Formula for Network Transmission:

$$\text{Monthly Charge} = \text{Load Ratio Share} \times \frac{\$56{,}146{,}133}{12}$$

Formula for Point-to-Point:

$$\text{Rate} = \frac{\$56{,}146{,}133}{1{,}354{,}899 \text{ kW}}$$

$$= \$\ 3.45 \ / \ \text{kW-month}$$

LAP Transmission Rate Components

Annual Transmission Revenue Requirement (ATRR) =

Annual Cost of Transmission System

\+ System Augmentation Expense

\- Scheduling and Dispatch Revenue Credits

\- Point-to-Point Transmission Revenue Credits

+/- Misc Charges/Credits

+/- Prior Year True-Up

LAP Transmission Rate Components

$$\frac{\text{Annual Cost of Transmission System}}{} = \frac{\text{LAP Transmission Plant}}{\text{Total LAP Plant}} \times \text{Annual Expenses (O\&M, Depreciation, Interest)}$$

- Minor change from existing methodology
  - Moving to '% of Plant' Methodology
  - Current Formula Uses an Annual Fixed Charge Rate

LAP Transmission Rate Components

- Change being proposed on Data Collection:
  - Projection of costs & loads for the upcoming year (e.g., estimated FY12 data for the FY12 rate) vs. 2-year old historical data.
    - Uses projections to estimate transmission rate components for the upcoming year. Projections are based on:
      - Budgeted Amounts
      - Historical Averages
    - Will allow Western to more effectively match cost recovery with the incurring of the cost.
      - Allows for collection of plant costs as soon as the plant is placed in service.
    - Provides for a ‘truing up’ of costs after the year is complete.

LAP Transmission Rate Components—Example of True-Up

- Year 1 Projected Rev Requirement = $50,000,000
- Year 1 Projected Load 2,500,000 kW

<u>2 years later</u>

- Year 1 Actual Rev Requirement = $51,000,000
- Year 1 Revenue Collected
  (including bundled w/FES) = <u>$48,000,000</u>

Difference $ 3,000,000

Two components of difference:

Change in Revenue Requirement	$ 1,000,000
Under-collection of projected revenue requirement due to over-estimation of load	<u>$ 2,000,000</u>
	$ 3,000,000

LAP Transmission Rate Components—Example of True-Up (Cont'd)

- Difference to be included with Year 3 projected revenue requirement:

Year 3 Projected Rev Requirement	$54,000,000
Year 1 True-Up	$ 3,000,000
Year 3 Adjusted Revenue Requirement	$57,000,000

Penalty Rate for Unreserved Use of Transmission
Schedule 10 (new)

- New Rate Schedule for Penalty Rate for Unreserved Use of Transmission (previously part of Transmission Rate Schedules).

  - 200% penalty for the period of unreserved use.
    - Base transmission charge.
      - Use FERC-defined periods (e.g., no hourly rate).
    - 100% penalty.

  - No distribution of penalty revenue above the base charge to non-offending customers. Revenue will be returned to customers via <u>credits</u> to future transmission revenue requirements.

Transmission Losses

- No change to Rate Schedule.
  - Rate as posted on the RMR Open Access Same-Time Information System (OASIS).
  - Energy Return or Financial Settlement.
    - Energy return concurrent or 7 days later, same profile.
  - WACM pricing.
- Postage stamp rate is currently 4.5%, as of Oct 1, 2010

Rate Proposals

WACM Ancillary Services

Scheduling & Dispatch Schedule 1

Proposed Formula

$$\text{Rate Per Schedule} = \frac{\text{Total Annual Revenue Requirement for Scheduling *}}{\text{Number of Schedules Per Year}}$$

* Changing description in numerator from 'Annual Cost of Scheduling and Dispatch Personnel, and Related Costs'

Estimated FY 12 Rate

$$\text{Rate Per Schedule} = \frac{\$\ 3{,}070{,}417}{122{,}778\ \text{Schedules}}$$

$$= \$\ 24.03 \text{ per Schedule per Day}$$

Scheduling & Dispatch

- Proposed Change on Data Collection
  - We’re more narrowly defining the costs recovered through this rate to be costs related to scheduling/tagging.
- Proposed Change on Implementation/Billing
  - The Schedule charge will be allocated equally among <u>all</u> Transmission Providers on the Schedule that are inside WACM, vs. entire charge being assessed to the last TP.
    - Under Western’s Tariff, WACM is performing this service for the TPs inside WACM.
    - Affects each TP differently, depending on the structure of the Schedules.
    - Federal transmission segments will be exempt from billing, as scheduling for these segments continues to be included in Federal transmission service.
    - More equitable method of cost allocation, since all TPs take the service.

Scheduling & Dispatch
Example of Billing

Three Transmission Providers on the Schedule
(2 inside WACM)…

Trans.Prov.	POD BA	Current Method	Proposed Method
TP #1	WACM		$ 12.015
TP #2	WACM	$ 24.03	$ 12.015
TP #3	BA #2	-	-
Total Collected for Schedule		$ 24.03	$ 24.03

Scheduling & Dispatch
Example of Billing

If LAPT or CRCM is a TP on the Schedule…

Trans.Prov.	POD BA	Current Method	Proposed Method
TP #1	WACM		$ 12.015
TP #2 (LAPT)	WACM	~~$ 24.03~~	~~$ 12.015~~
Total Collected for Schedule		~~$ 24.03~~ -0-	~~$ 24.03~~ 12.015

Reactive Supply (or VAR Support)
Schedule 2

Formula

$$\text{VAR Support Rate} = \frac{\text{TARRG} \times \text{\% of Resource}}{\text{Load Requiring VAR Support}}$$

Where:

TARRG = Total Annual Revenue Requirement for Generation

% of Resource = Percentage of Resource Capacity Used for VAR Support
= (1 minus power factor)

Load Requiring VAR Support = Trans 12-cp minus self supply/waivers

No Change to Existing Formula

Estimated FY 12 Rate

Inputting the TARRG and % of Resource for both LAP and CRSP generators, and reflecting a credit for VAR support revenue on point-to-point transactions:

$$\text{VAR Support Rate} = \frac{\overset{\text{LAP}}{(\$\,62{,}278{,}365 \times 5.824\%)} + \overset{\text{CRSP}}{(\$50{,}165{,}998 \times 4.9429\% \times 0.5^{*})} - \$53{,}524}{1{,}260{,}472 \text{ kW}}$$

= $ 0.318 / kW-month

*** ½ of CRSP Revenue Requirement is allocated to WACM**

Reactive Supply

- Change being proposed on Data Collection:
  - % of Resource will be based on weighted average of unit nameplate values (1-PF). Currently, it's based on actual unit performance data.

	Proposed	Current
LAP Units	5.78%	2.9%
CRSP Units	4.94%	3.6%

Regulation & Frequency Response Schedule 3

- Four components to Regulation Service:
  - Load-based Assessment
  - Exporting Intermittent Generator Requirement
  - Self-provision by a Sub-BA Using AGC
  - Other Self- or Third-party Supply

Formula

$$\text{Regulation Service Rate} = \frac{\text{Total Annual Revenue Requirement for Regulation Service}}{\text{Load inside WACM Requiring Regulation Service Plus the Installed Nameplate of Intermittent Generators Serving Load } \underline{\textit{inside}} \text{ WACM}}$$

- **Load is a 12-cp calculation (on the LAP system peak) of loads inside WACM taking this service (not necessarily on the LAP system).**
- **Restricting this service to intermittent generators serving load *inside* WACM is a change from the current rate (see ‘Exporting Intermittent Resource Requirement’ following).**

Estimated FY 12 Rate

$$\text{Regulation Service Rate} = \frac{\$\ 11{,}659{,}643}{3{,}016{,}548\ \text{kW}}$$

$$= \$\ .322\ /\ \text{kW-month}$$

Regulation & Frequency Response Load-based Assessment

- Revenue requirement includes:
  - Plant costs for regulation from LAP units (Amount of required regulation capacity to be re-evaluated every year).
  - Purchased regulation.
  - Power purchases needed to support the ability of the LAP units to regulate upward during on-peak periods.
  - Lost sales opportunity from having to generate in off-peak hours to support downward regulation.
  - Third-party transmission costs associated with regulating.
  - Costs for regulation from CRSP units.
- Denominator is BA load requiring regulation, <u>including</u> load served by Federal allocations, plus installed nameplate of intermittent resources serving load **<u>inside</u>** WACM.

Regulation & Frequency Response Example of Billing

Example

Customer A:

12-cp Aux Load inside WACM* = 150,000 kW

Wind generator serving load in WACM = 8,000 kW (nameplate)

FY 2012 Proposed Regulation Rate = $0.322/kW-month

Monthly Invoice:

Load	150,000 x $0.322	=	$ 48,300
Wind	8,000 x $0.322	=	2,576
	Total		$ 50,876

* Including all loads, not just those loads on the LAP transmission system.

Regulation & Frequency Response
Exporting Intermittent Generator Requirement

- Change being proposed for current Exporting Intermittent Generator Assessment:
  - There will no longer be a Load-based Assessment.
  - There will no longer be a Regulating Reserve Charge for mismatched capacity.

Instead…

  - An intermittent generator not serving load inside WACM will be required to be dynamically removed from WACM:
    - Pseudo-tie
    - Dynamic Schedule
  - Requires metering/communication changes.
  - Customer must still purchase transmission.

Regulation & Frequency Response
Self-Provision by a Sub-BA Using AGC

- Change being proposed to the current Self-Provision Assessment:

  - Currently, self-provision can be measured by use of the 1-minute average of the customer's ACE **or** the

    1-minute average of the first derivative of the customer's ACE (customer's choice).

Instead…

  - Assessment will be measured only by the 1-minute average of the customer's ACE.
    - More accurate measurement of the service being provided.

Regulation & Frequency Response
Other Self- or Third-Party Supply

- WACM may allow an entity to supply some or all of its required regulation, even without being a sub-balancing authority, or contract with a third party to do so. WACM will evaluate the entity's metering, telecommunications and regulating resource, as well as the required level of regulation, and determine whether the entity qualifies to Self-supply under this provision.

Operating Reserves—Spinning & Supplemental Schedules 5 & 6

- No change to rate schedules for Spinning and Supplemental Reserves.
- WACM has no long-term Reserves available for sale.
- At a customer's request, WACM will purchase Reserves and pass through that cost and the cost of any activation energy, plus a fee for administration. The customer would be responsible for providing the transmission to deliver the Reserves.

Energy Imbalance
Schedule 4

Energy Imbalance = Resources – Obligations

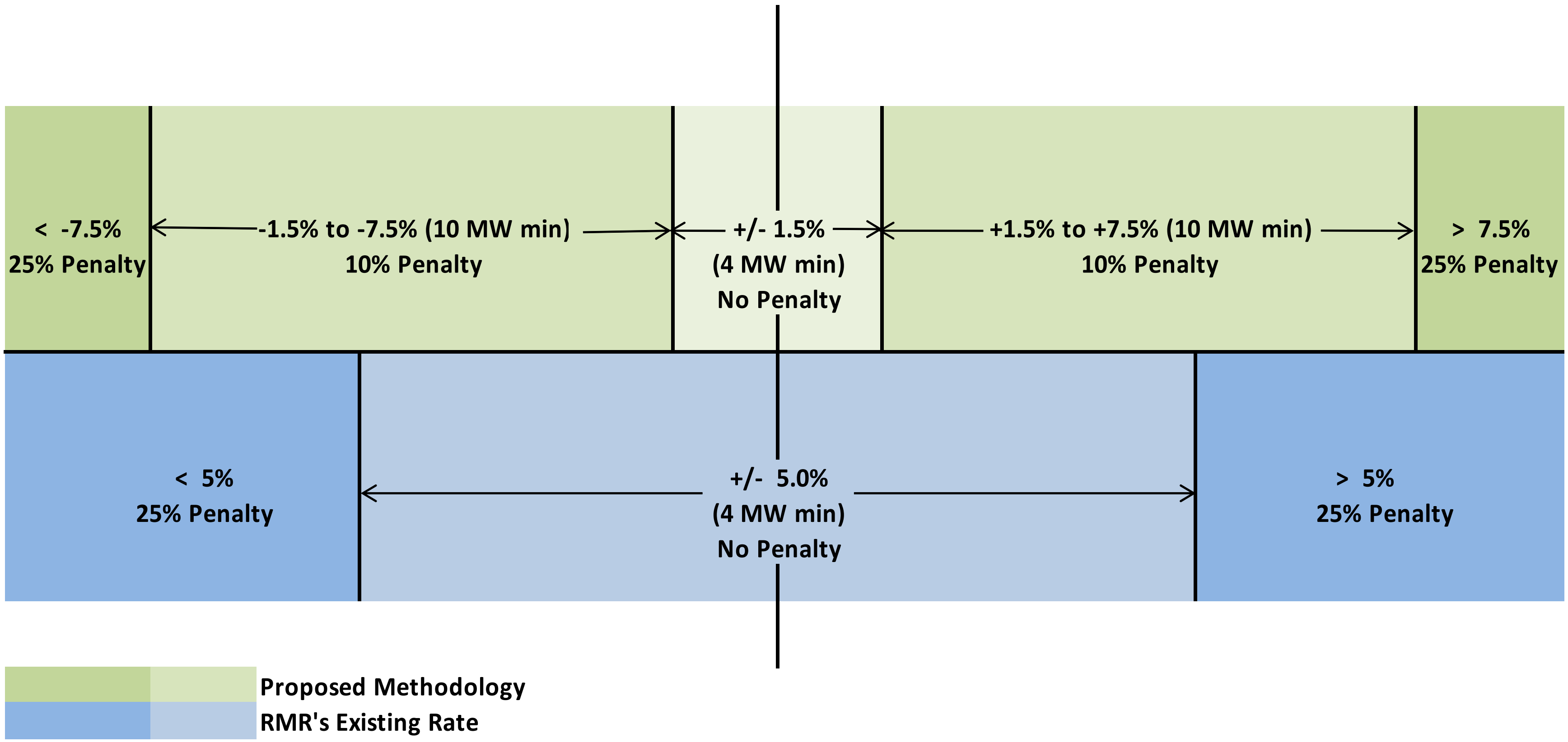
Where Resources = Generation (actual and/or scheduled), purchases of energy, interchange (in)

Obligations= Metered load, sales of energy, interchange (out)

Energy Imbalance
Schedule 4

ENERGY IMBALANCE BANDWIDTHS

Undersupply **Oversupply**



Existing Rate - Imbalances settled using WACM pricing.

Proposed Method - Imbalances settled using WACM pricing based on BA aggregate only.

Energy Imbalance

- Features of EI implementation:
  - Bandwidths will continue to be calculated on metered load. *
  - Continued use of 4 MW minimum on first band.*
  - No monthly netting of in-band energy (continuation of current methodology).*
  - Continued use of WACM Pricing as representative of incremental cost. However, the Balancing Authority Aggregate will determine pricing in all bands. This is a change from the current formula.
    - Aggregate Positive = Sales Pricing
    - Aggregate Negative= Purchase Pricing
  - No redistribution of penalty revenue to non-offending customers.*
  - No administrative charge.

Energy & Generator Imbalance Bandwidth Expansion

- Expansion of the bandwidth may be done to accommodate:
  - Physical Loss of Resource.
    - In the first hour of a coordinated response by a Western-recognized reserve sharing group, such as the Rocky Mountain Reserve Group.
      - Ramping period for entities responding to the event.
  - Transitioning of large base-load thermal resources between on-line and off-line.
    - When generation is below the agreed-upon minimum scheduling level.
      - Western would like to re-verify those levels with existing customers.

General Effects of Proposed Bandwidth and Penalty Structure On Invoicing for FY 2009

- Large Customers—Amounts billed would have increased, as there is now a penalty for deviations between 1.5% and 5%.
- Small Customers—Amounts billed would have decreased, as the penalty for excursions beyond the 4 MW minimum have decreased from 25% to 10%.
- Wind Units—Amounts billed would have increased, as there is now a band with an associated penalty.
- Multi-party Generators—Results were mixed, as the bandwidth was already at 2% and is changing to 1.5%.

These are the general trends noted by applying the proposed bandwidth and penalty structure to FY09 performance and do not imply a guarantee of future results.

Generator Imbalance
Schedule 9

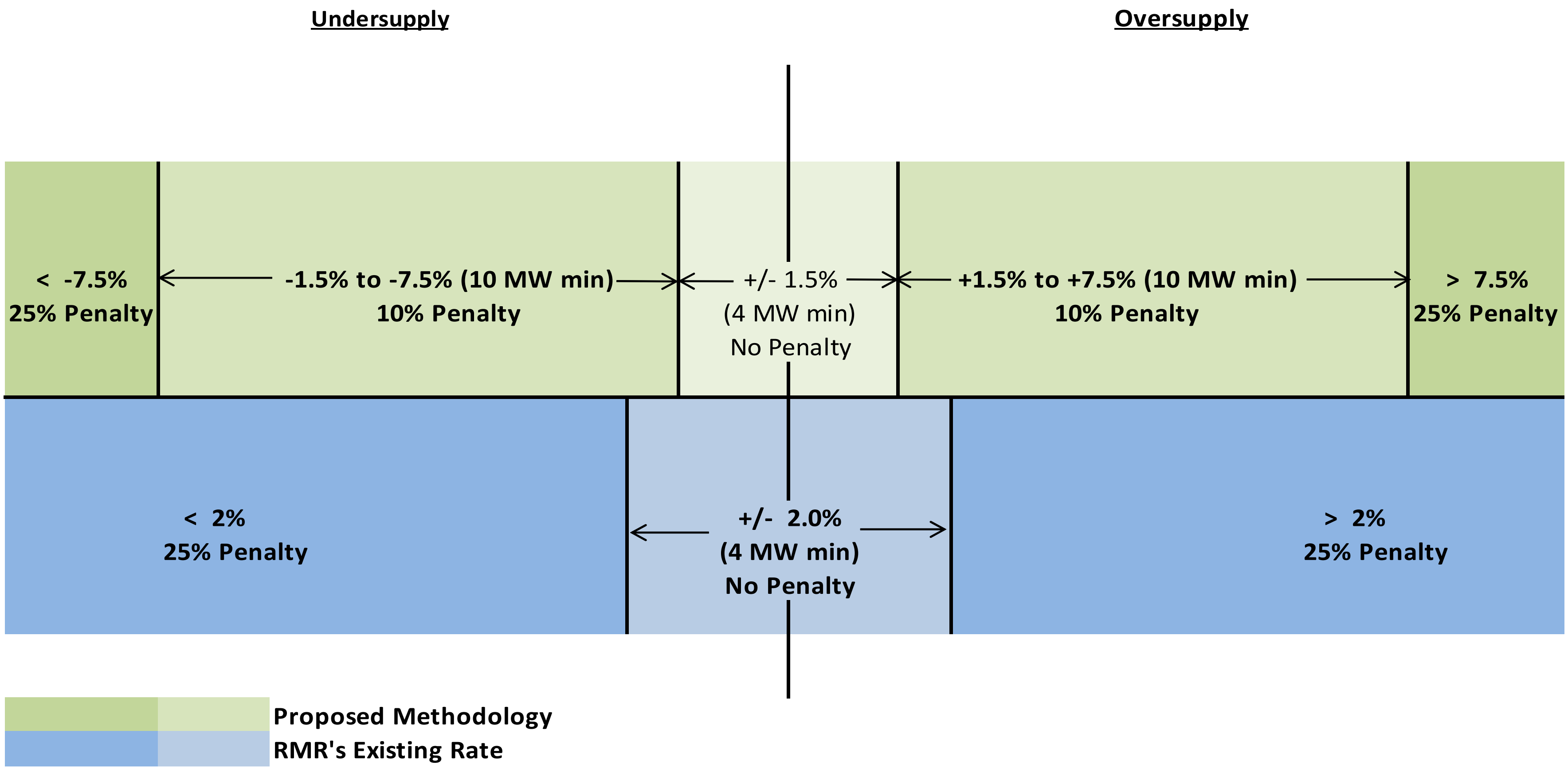
Generator Imbalance = Resources – Obligations

Where Resources = Actual Generation

Obligations= Scheduled Generation

Generator Imbalance
Schedule 9 (new)

GENERATOR IMBALANCE BANDWIDTHS



Existing Rate - Imbalances settled using WACM pricing.
Proposed Method - Imbalances settled using WACM pricing based on BA aggregate only.

Generator Imbalance

- Features of GI Implementation:
  - Same bandwidth and penalty structure as with Energy Imbalance calculations.
    - Calculated on metered generation (vs. load).
    - No 7.5% bandwidth (3rd band) for intermittent resources.
  - Will apply to:
    - Jointly-owned generation facilities opting not to allocate generation.
    - Intermittent generation facilities serving load in the WACM balancing authority.
    - Non-intermittent generation facilities that export their entire output.
  - Solely-owned non-intermittent generation will continue to be combined with the <u>Energy</u> Imbalance calculation.
  - Continued use of 4 MW minimum & WACM pricing (incl. the change to use balancing authority aggregate to determine pricing in all bands).
  - No redistribution of penalty revenue to non-offending customers.

Generator Imbalance Penalty Elimination

- FERC Order 890 stipulation:
  - The Balancing Authority cannot assess penalties in an entity's Energy Imbalance <u>and</u> Generator Imbalance calculations in the same hour unless the imbalances aggregate rather than offset.
    - Western <u>will</u> eliminate the penalty in the Generator Imbalance calculation in hours in which penalties are present in both calculations, and the imbalances offset.

Generator Imbalance
Jointly-Owned Generators

- Jointly-owned generators will have the option to:
  - Be treated as "stand alone", with their own generator imbalance calculations.
    - There will be no penalty elimination in the calculation based on the presence of penalties in the participants' related Energy Imbalance calculations.
  - Allocate the facility generation to the individual participants.
    - If the facility is <u>not</u> an intermittent, the generation will be included as a resource in the participants' Energy Imbalance calculation.
    - If the facility <u>is</u> intermittent, the generation will be included with the participant's Generator Imbalance calculation. Penalties will be eliminated as discussed on the previous slide.

Energy & Generator Imbalance Examples

How Jointly-Owned Generators Work-Method A (“Stand-Alone”, with Participant Schedules)

Generator X **(coal)**		A	B	C	
Actual Generation	510 MW				
Participant A	200 MW →	200			Forecast Generation
Participant B	175 →		175		
Participant C	125 →			125	
Total	500 MW				
		210	171	127	Load (MW)
Imbalance	10 MW	- 10	+ 4	- 2	Imbalance

Generator Imbalance = 10

Energy Imbalance = -8

Total Imbalance Captured = 2

Energy & Generator Imbalance Examples

How Jointly-Owned Generators Work-Method B (Generation is Allocated)

Generator X **(coal)**		A	B	C	
Actual Generation	510 MW				
Participant A	205 MW	205			Actual Generation
Participant B	177		177		
Participant C	128			128	
Total	510 MW				
		210	171	127	Load (MW)
Imbalance	N/A	- 5	+ 6	+ 1	Imbalance

No Generator Imbalance

Energy Imbalance = 2

Total Imbalance Captured = 2

WESTERN AREA POWER ADMINISTRATION

Energy & Generator Imbalance Examples

How Jointly-Owned Generators Work-Method A (“Stand-Alone”, Participant Schedules)

Generator X (Intermittent)		A	B	C	
Actual Generation	510 MW				
Participant A	200 MW	200			Forecast Generation
Participant B	175		175		
Participant C	125			125	
Total	500 MW				
		210	171	127	Load (MW)
Imbalance	10 MW	- 10	+ 4	- 2	Imbalance

Generator Imbalance = 10

Energy Imbalance = -8

Total Imbalance = 2

How Jointly-Owned Generators Work-Method B

(Generation is Allocated)

Generator X **(Intermittent)**			A	A	
Actual Generation	510 MW			200	Forecast Generation
Participant A	205 MW		205		
Participant B	177				
Participant C	128				
Total	510 MW				
		Forecast Gen	200	210	Load (MW)
Imbalance	N/A		+ 5	- 10	Imbalance
No Generator Imbalance			Generator Imbalance	Energy Imbalance	

In Summary

- Transmission
  - Projecting Cost and Load
- Scheduling and Dispatch
  - Capture scheduling & related costs only
  - Schedule cost allocated to each transmission provider on schedule inside WACM
- Reactive Supply
  - % of resource based on generator nameplate
- Regulation
  - Exporting Intermittent—requirement to dynamic out
  - Self-provision using AGC—based on customer ACE
- Energy Imbalance
  - New Bandwidth and penalty structure
  - Pricing in all bands based on BA Aggregate
  - No Administrative Charge
- New Penalty Rate for Unreserved Use of Transmission
- New Generator Imbalance Rate
  - Elimination of penalties in certain circumstances

Next Steps

- Public comment forum will be held this afternoon at 1:00 in this room.
- Consultation and comment period closes April 28, 2011. Written comments must be submitted by that date to be considered by Western's in its decision process.
- *Federal Register* Notice with final formula rates to be published in late August 2011.
- Proposed effective date of October 1, 2011.

Contact Information

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For further information relating to these rate proposals, visit our website at http://www.wapa.gov/rm/ratesRM/2012/default.htm

Questions?

Western Area Power Administration

Comment Forum

1:00—NLT 2:30

Please provide verbal comments at the Comment Forum or send written comments, via e-mail or letter, by April 28, 2011